Renewable and Sustainable Energy Reviews 41 (2015) 1037–1051

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Potential residential PV development in Chile: The effect of Net Metering and Net Billing schemes for grid-connected PV systems

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ARTICLE INFO

Article history:
Received 7 January 2014
Received in revised form
18 July 2014
Accepted 30 July 2014

Keywords:
Grid-connected photovoltaic
Residential PV system
Chile
Net Metering
Net Billing
Levelized cost of electricity

ABSTRACT

In recent years the global photovoltaic (PV) market has expanded rapidly due to a sharp decline in PV prices and increased attention to the importance of sustainable energy. Northern Chile has one of the highest irradiance levels in the world as well as one the highest electricity rates in Latin America. Because of these conditions, Chile is one of very few countries where several PV projects are being developed without government subsidies and consequently, the PV industry is experiencing rapid growth.

This paper reviews the opportunity to take advantage of these market conditions within the residential sector, modeling PV arrays across 10 cities in Chile. A detailed modeling of PV systems is performed to achieve an accurate analysis of energy production and electricity cost, using local resource data, optimal array orientation and inclination, and production losses.

A review of how Net Metering and Net Billing affect the value of the PV production is applied and a comparison using levelized cost of electricity (LCOE) is conducted. Net Metering is found to be a better policy choice to promote PV systems than Net Billing because energy injected into the electrical network is paid at the complete retail rate. However, in developed countries this kind of policy is unlikely to be supported because of it's economic unfeasibility. Under a Net Billing scheme a consumer will see an advantage when energy is recorded over longer time intervals and when installing a system with smaller capacity relative to household electricity consumption. This prevents excess generation from being injected into the network which would be bought by the utility at lower prices than the retail rate. Payback periods are found to be low, between 6 years in northern areas with high retail rates and 13 years in other areas with lower radiation and retail rates.

Contents

Abbreviations: LCOE, Levilized cost of electricity; GHI, Global Horizontal Irradiance; PV, Photovoltaic; PR, Performance Ratio; IR, Inverter Ratio

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http://dx.doi.org/10.1016/j.rser.2014.07.201
1364-0321/

1. Introduction

The development of solar PV market and the use of this technology worldwide has grown at annual rates of 35–40% [1]. This rapid expansion is due to a sharp decline in PV prices and increased attention to the importance of sustainable energy. Moreover, progressive, decreasing module prices which are coming from China (well below 1 US$/W) [2,3] have enabled the development of profitable PV systems at all scales.

Some counties in northern Chile have some of the world's highest irradiation levels, with average daily Global Horizontal Irradiance (GHI) above 7 kWh/m^2 [4] and Direct Normal Irradiation (DNI) above 9–10 kWh/m^2 [4]. As an example, the city of Calama has a GHI of 7.22 kWh/m^2 and is surrounded by desert. The location is of high potential for both large-scale and residential PV installations. Moreover, since northern Chile has one of the highest levels of solar radiation in the world and northern and central Chile have some of the highest electricity rates in Latin America, several areas of Chile offer optimal conditions for PV development [5] even without government subsidies.

It is the role of the government to understand the international context as well as local opportunities for solar development considering the high electricity rates that are reaching the level of crisis in the energy sector. Indeed, it is the government that can take a leadership role in helping to exploit these opportunities and enable a local solar PV development. In the Residential PV sector, the old electricity laws in Chile did not consider the prospect of customers selling energy into the grid and a new policy design was needed. The Net Metering and Net Billing debate started a few years ago, aimed at enabling small scale distributed generation in the country, especially PV, micro-hydro and micro-CHP.

Net Metering is an electricity policy which enables utility customers to own, operate and profit from a PV system (or other generation technology) offsetting some or all their electricity consumption and getting paid for excess energy injected into the grid. Typically a low-cost meter is used that is able to spin in both directions, showing the net consumption or the net excess during the billing period, which is finally valued at retail rate [6]. Net Billing is a variant from Net Metering, that uses two one-directional meters or one meter with two data-records, keeping the measured consumption from the grid and the excess injected into the grid in separate records, valuing them separately and at a different price. The difference between valued grid consumption and valued excess injections is billed to the costumers. The electricity injected back into the grid is valued at a price which is lower than the retail rate because only the energy component is paid out (whereas a typical retail rate also includes a distribution charge).

In Chile, a Net Billing scheme was approved for small generators with capacities up to 100 kW, through the law No. 20.571 in February 2013 [7]. However new changes to this law are in discussion, where a Net Metering scheme is suggested for consumers with capacities of up to 10 kW [8] (10 kW is consistent with the largest system reviewed in this study). In Net Billing, when only one meter is used, the definition of integration intervals that the meters use is essential to establish the cost-effectiveness of generation systems. Meters record high frequency readings, but can be programed to add those readings up over a specified time period (called an integration interval) and to compute one final reading which is stored as either net consumption or net production. The length of this integration interval proves to be important to the economic feasibility of PV installations under Net Billing because it establishes how much energy is valued at a high rate (consumer rate) and how much at a low rate (excess). We found this concept to be underexplored in energy literature.

This paper has three main contributions. The first contribution is to identify the production potential of PV systems based on radiation levels in 10 different cities of Chile. The second contribution is to establish optimal orientations and inclinations of PV modules to maximize the incident radiation and then estimate the PV production based on typical power losses. The third contribution is to identify the cities with the best PV potential under Net Metering and Net Billing tariff schemes, obtaining PV energy prices, which are compared by their levelized cost of electricity.

The paper is organized as follows: Section 2 provides a radiation analysis for 10 cities and determines the optimal photovoltaic system orientation and inclination and inverter sizing ratio. Section 3 presents the PV system production model. Section 4 explains Net Metering and Net Billing tariff schemes and how they are modeled considering consumption and compares the results of different integration intervals. Section 5 presents a levelized cost of energy, payback periods and IRR analysis. Finally, Section 6 presents the conclusions.

2. Residential scale PV analysis

2.1. Cities considered and their main characteristics

In order to understand a cross section of PV potential across Chile, 10 cities were studied. For each city, the following local resource and electricity rate data was used:

- The global horizontal irradiance (GHI) from year 2010 and the mean GHI from years 2003–2011.
- The temperature from year 2010.

- The electricity retail rate named "Baja Tension 1" (BT1). This is the more commonly used rate in Chile and combines energy and capacity rate.
- The electricity energy-only rate named "Baja Tension 2" (BT2). This is the energy-only rate for clients who pay capacity (peak power consumption) separately from energy.

Rate and cost data is presented in both Chilean pesos and US dollars to provide information to both international and local analysts. The exchange rate used is the average dollar observed in Chile between 2012 and 2013 (1 $US = 496 $CL).

The geographical range of the study spanned 2381 kilometers, with Iquique as the northernmost city considered and Puerto Montt representing the southernmost city, covering more than 99% of the population of the country and the most important PV potential. Table 1 summarizes key characteristics for each location that was used in this study.

Radiation and temperature data were obtained from Chile's *Explorador Solar* resource database [9] maintained by the Government of Chile. When solar resource information was not available, it was estimated using other meteorological parameters such as temperature and relative humidity [10] or forecasted with a probabilistic approach [11]. The electricity rates were obtained from each utility's tariff reports.

Ovalle (BT1: 0.27 US$/kWh and BT2: 0.147 US$/kWh) and Coquimbo (BT1: 0.243 US$/kWh and BT2: 0.147 US$/kWh) had the highest electricity rates, while the city with the higher GHI is Calama with an average of 7.21 kWh/m^2 day, followed away for Copiapó, Iquique and Antofagasta with averages of 6.31, 6.19 and 6.13 kWh/m^2 day respectively.

2.2. Solar resource

In Chile, inland cities have more solar radiation than coastal cities because of cloud cover near the coast. This is presented graphically in Fig. 1, which shows GHI throughout Chile.

The GHI data used has a resolution of 30 min and represents irradiances at exact times (rather than averages), which are referenced to GMT/UTC – 4 time [9]. In 2010, of the cities profiled in this study, Calama had the highest total GHI (2.632 kWh/m^2 year) and the Puerto Montt had the lowest (1.292 kWh/m^2 year). Monthly, the GHI in average is between 9 kWh/m^2 day (Calama) and 5 kWh/m^2 day (Coquimbo) in summer, and between 5 kWh/m^2 day (Calama) and 1 kWh/m^2 day (Puerto Montt) in winter. Fig. 2 shows the annual GHI for all locations and Fig. 3 the daily average GHI for all locations.

2.3. Inclination and orientation analysis and optimization

GHI measurements used did not present direct beam and diffuse radiation separately nor did they include values of incident radiation over an inclined and oriented plane [12]. The optimal orientation and inclination that would maximize the total PV

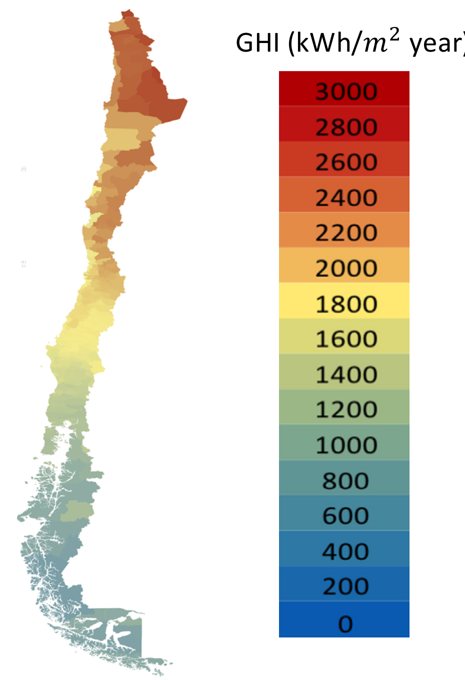

Fig. 1. Global Horizontal Irradiance (GHI) throughout Chile.

Table 1
Input data for each location: coordinates, temperature, GHI 2010, average GHI 2003–2011, utility and BT1 and BT2 tariffs.

City	Geographic coordinates	Average temperature 2010 (°C)	Daily average GHI 2010 (kWh/m^2 day)	Daily average GHI 2003–2011 (kWh/m^2 day)	Utility name	BT1 tariff retail rate June 2013 ($CL/kWh) ($US/kWh)[a]	BT2 tariff energy rate June 2013 ($CL/kWh) ($US/kWh)[a]
Iquique	Lat: −20.22° Long: −70.14°	17.5°	6.06	6.19	Eliqsa	99.8 0.201	53.72 0.108
Calama	Lat: −22.45° Long: −68.93°	11.8°	7.22	7.21	Elecda	91.3 0.184	53.71 0.108
Antofagasta	Lat: −23.65° Long: −70.4°	16.1°	6.06	6.13	Elecda	91.3 0.184	53.71 0.108
Copiapó	Lat: −27.37° Long: −70.33°	16.8°	6.25	6.31	Emelat	103.76 0.209	62.94 0.127
Coquimbo	Lat: −29.96° Long: −71.34°	14.9°	4.66	4.9	Conafe	120.77 0.243	67.7 0.136
Ovalle	Lat: −30.6° Long: −71.2°	15.3°	5.81	5.87	Enelsa	133.85 0.270	73.01 0.147
Valparaíso	Lat: −33.05° Long: −71.62°	14.8°	4.64	4.74	Conafe	107.75 0.217	59.07 0.119
Santiago	Lat: −33.41° Long: −70.55°	13.5°	5.73	5.65	Chilectra	83.51 0.168	49.87 0.101
Concepción	Lat: −36.82° Long: −73.05°	12.4°	4.89	5.01	CGE Distribución	94.12 0.190	56.41 0.114
Puerto Montt	Lat: −41.47° Long: −72.94°	10.4°	3.54	3.69	Saesa	121.14 0.244	56.75 0.114

[a] $US = 496 $CL (equivalent to the average dollar observed in Chile between 2012 and 2013).

generation during the year in order to offset as much local consumption as possible was calculated [13].

There are two different sky models that estimate the total radiation over an oriented and inclined plane: the Isotropic and the Anisotropic diffuse radiation models. Both define three components: direct beam, diffuse, and solar radiation diffusely reflected from the ground [14,15]. The Isotropic model interprets diffuse radiation as if it were identical in all directions and tends to underestimate the total incident radiation, while an Anisotropic model estimates the diffuse radiation distribution on the sky, obtaining more accurate results. However, some studies suggest that the PV production estimation differs by only 1% or 2% in some places [16], presumably those with low diffuse radiation.

For this study, the Anisotropic model presented by Duffie and Beckman [14] was used. Table 2 summarizes the optimal azimuth and slope to maximize de incident radiation for PV projects at each city. The gain (R) is measured with respect to GHI (e.g. a gain of 6% in Calama means that an array configured with its optimal orientation and inclination would have an incident energy in the module 6% higher than it would if it were oriented horizontally, receiving the expected GHI).

The optimal orientation is usually north, particularly in the cities of Iquique, Calama, Santiago and Concepción. Coquimbo represents the largest deviation from North with an optimal orientation of 32° northwest using the 2003–2011 resource data along with the Duffie and Beckman model [14].

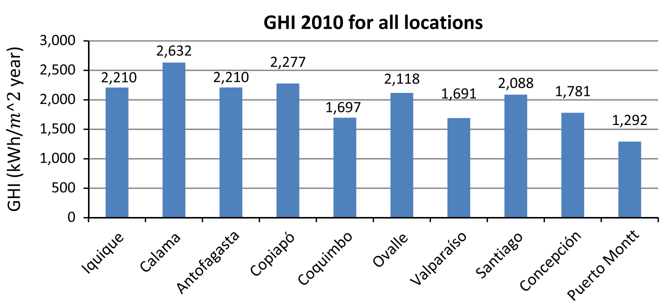

Fig. 2. GHI 2010 for all locations.

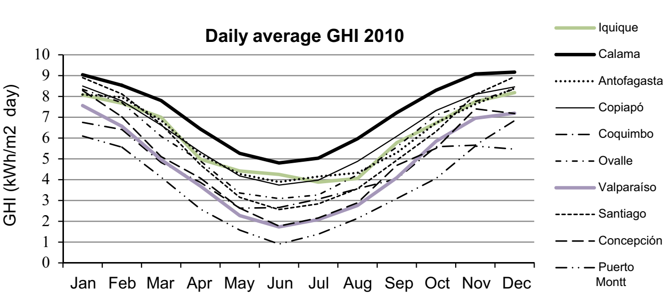

Fig. 3. Daily average GHI monthly 2010 for all locations.

Towards the south of Chile, the optimum inclination or tilt, tends to increase because the solar height decreases (especially in winter months). For instance, the optimal tilt in Iquique (in northern Chile) is 16º, while the optimal tilt is 29º in Concepción (in the south). Similarly, using the optimal tilt is more relevant in the south to make PV system investment economically feasible because of the lower average solar height.

3. PV energy production analysis

This study calculates energy production for grid-connected PV systems of three representative sizes: 1 kW, 3 kW and 10 kW. The main components include PV modules, the mounting system, inverter, electrical panel, cables and connections, together with the house meter and the electric grid. All household loads are fed by both the PV system electricity and conventional electricity from the grid. The configurations of the example systems used in this study are shown in Fig. 4a, b and c.

3.1. Inverter system sizing

Usually module capacity should be greater than the nominal inverter capacity due to (a) the global horizontal irradiance (GHI) in average during the day being less than the standard irradiance used with the PV modules (1000 W/m^2), (b) the modules temperature being higher than the modules standard test conditions (STC), and (c) the power loss sources between the modules and the inverter. Therefore, the inverter ratio (IR), the capacity of the PV modules (KWp DC) divided by capacity of the inverter (KW AC), is not assumed to be 1.0. For each location a different inverter ratio is used, according to the local radiation levels. The major power losses and efficiencies are applied to determine the total energy production. Fig. 5 illustrates point (a) above, showing that the average hourly irradiance is less than standard 1000 W/m^2 in all locations

For simplicity, the following approximation was used to compute the optimal inverter ratio [17]:

$$IR = \frac{P_{array\_stc}}{P_{Nom\_inv}} \approx \frac{1}{PR} \quad (1)$$

where IR is the inverter ratio, P_{array_stc} corresponds to the DC peak power for all of the PV modules connected to the inverter, P_{Nom_inv} corresponds to the nominal AC power of the inverter, and PR corresponds to the performance ratio. This expression is presented by Omar and Shaari [17] who also relate the Inverter Ratio (IR) with a Derate Factor based on the GHI, temperature and losses, leading to an index similar to Performance Ratio (PR). However, as the array's capacity grows, the investment cost rises, and generally the power losses are underestimated and efficiencies are overestimated if low resolution data is used [18]. Thus, another criteria used in this work to choose an appropriate IR is to avoid overloads at any hour of the year (except in the case of Puerto Montt, due to

Table 2
Optimal orientation, inclination, and gain coefficient R with respect to GHI.

GHI 2010	**Iquique**	**Calama**	**Antofagasta**	**Copiapó**	**Coquimbo**	**Ovalle**	**Valparaíso**	**Santiago**	**Concepción**	**Puerto Montt**
***R* Gain**	3.00%	6.11%	5.06%	8.91%	9.02%	9.71%	5.73%	9.92%	11.16%	9.17%
Azimuth (γ)	182º	180º	192º	166º	152º	168º	164º	180º	178º	175º
Slope (β °)	16º	21º	20º	25º	26º	27º	22º	27º	29º	28º
GHI 2003–2011	**Iquique**	**Calama**	**Antofagasta**	**Copiapó**	**Coquimbo**	**Ovalle**	**Valparaíso**	**Santiago**	**Concepción**	**Puerto Montt**
R Gain	3.37%	6.43%	5.18%	9.02%	8.24%	8.87%	4.74%	8.38%	9.00%	6.15%
Azimuth (γ)	182º	181º	192º	164º	148º	164º	154º	180º	174º	176º
Slope (β °)	17º	22º	20º	26º	26º	26º	21º	25º	27º	25º

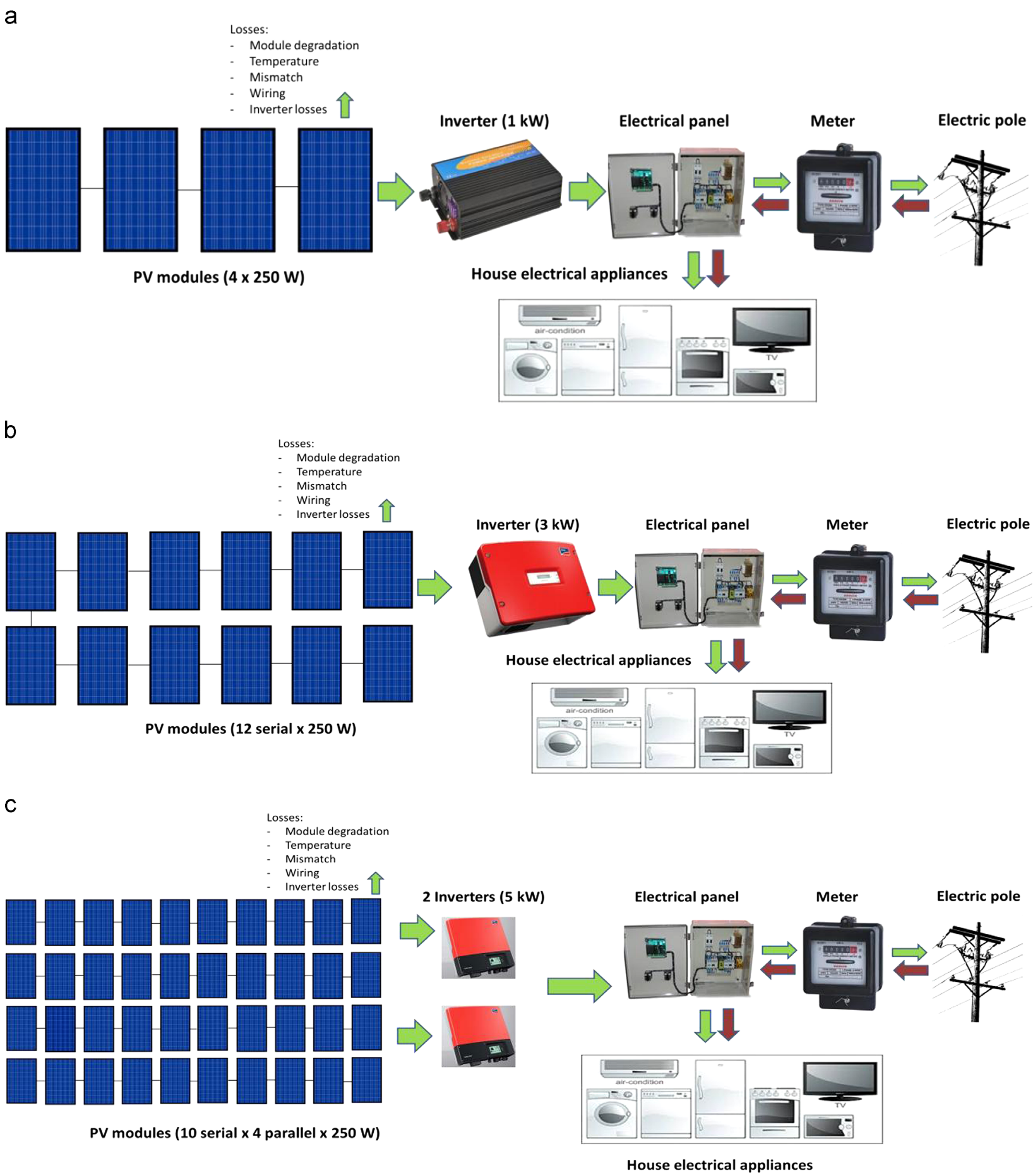

Fig. 4. Main grid-connected PV components for a 1 kW (a), 3 kW (b) and 10 kW (c) PV systems. In (a) 4 PV modules are connected in series, in (b) there are 10 connected in series and in (c) there are four groups of 10 modules connected in series, with two groups in parallel connection for each inverter.

its very low GHI). For a review of different methods to optimize the inverter size depending on local solar radiation, ambient temperature and inverter performance see Khatib et al. [19].

The actual IR differs from the optimal (ideal) computed above due to indivisibility of module capacity. Actual IRs ranged between 1.05 (Calama) and 1.25 (Puerto Montt). This difference is the greatest with smaller systems such as the 1KW example used here. These values of IRs are in line with those presented by Mondol [20], who shows that for systems with high inverter efficiency (like those used in this study) the optimal IR is among 1.1 and 1.3. Table 3 shows the actual PV array sized to be as close as possible to the required IR.

3.2. PV modules and inverter

In this work the PV module used to estimate a typical efficiency curve is Kyocera LA361K51, a polycrystalline silicon technology module with 12.7% efficiency. This module was studied by Durisch et al. [21] who made a semi-empiric model of its operation.

The inverter used comes from a model implemented by Notton et al. [22], who after studying various models of inverters, determined the existence of three typical families of inverters. This study uses the most efficient of the inverters modeled by Notton.

3.2.1. Module efficiency

The PV module efficiency depends primarily on the irradiance incident on the plane and the PV cell temperature (which is considered later as temperature losses). A model is established by Durisch et al. [21] who determined an expression to represent its efficiency curve considering these variables. In this work a version of Durisch's model is used, which considers only the irradiance as presented in Eq. (2).

$$n_{25^\circ,1.5AM} = p\cdot[q\cdot\frac{G}{G_0}+\left(\frac{G}{G_0}\right)^m]\cdot(2+r+s) \tag{2}$$

where G is the incident irradiance on modules, G_0 is 1000 W/m^2 and factors p, q, r, y, s depends on the modules used. For this module in particular, these factors are shown in Table 4.

Fig. 6 shows the efficiency curve as a function of the irradiance for the Kyocera LA361K51 PV module.

3.2.2. Inverter efficiency

Inverter efficiency is estimated using a model that represents its efficiency curve, using just the efficiency data at 10% and 100% of its nominal capacity (n_{10} and n_{100}) [22]. The model used only depends on the value of the AC power leaving the inverter expressed in the quadratic formula and the efficiency at 10% and 100% of the inverter's capacity. Eqs. (3) (through 6) express how the inverter efficiency was estimated.

$$n_{inv} = \frac{p}{p+p_0+kp^2} \tag{3}$$

where

$$p_0 = \frac{1}{99}\left(\frac{10}{n_{10}}-\frac{1}{n_{100}}-9\right) \tag{4}$$

$$k = \left(\frac{1}{n_{100}}\right)-p_0-1 \tag{5}$$

$$p = \frac{P_{out}}{P_{inv,rated}} \tag{6}$$

where n_{inv} is the efficiency of the inverter, P_{out} is the AC power leaving the inverter, $P_{inv,rated}$ is the AC nominal power of the inverter, n_{10} is the efficiency at 10% nominal capacity and n_{100} is the efficiency at 100% nominal capacity.

In this work a low losses inverter is used, with an efficiency of 96% operating at nominal capacity (n_{100}) and 93–10% load (n_{10}). The inverter efficiency curve is shown in Fig. 7.

Table 4
Factors used by Durisch et al. [21] in his semi-empirical model.

Factors	Value
P	15.39
Q	−0.177
M	0.0794
R	−0.09736
S	−0.8998

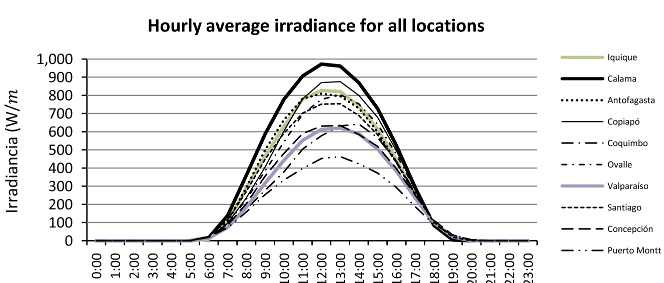

Fig. 5. Hourly average irradiance for all locations.

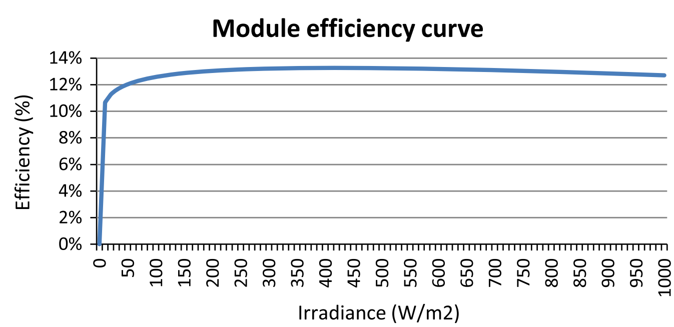

Fig. 6. Module efficiency curve.

Table 3
Inverter Ratio (IR) used for each city.

		1 kW inverter			3 kW inverter			10 kW inverter		
Ciudad	**IR$_{ideal}$**	**PV panels**		**IR$_{250W}$**	**PV panels**		**IR$_{250W}$**	**PV panels**		**IR$_{250W}$**
		IR = 1	**IR$_{Actual\ 250W}$**	**Actual**	**IR = 1**	**IR$_{Actual\ 250W}$**	**Actual**	**IR = 1**	**IR$_{Actual\ 250W}$**	**Actual**
Iquique	1.15	4 × 250	5 × 250	1.25	12 × 250	14 × 250	1.17	40 × 250	46 × 250	1.15
Calama	1.05	4 × 250	4 × 250	1	12 × 250	13 × 250	1.08	40 × 250	42 × 250	1.05
Antofagasta	1.15	4 × 250	5 × 250	1.25	12 × 250	14 × 250	1.17	40 × 250	46 × 250	1.15
Copiapó	1.1	4 × 250	4 × 250	1	12 × 250	13 × 250	1.08	40 × 250	44 × 250	1.1
Coquimbo	1.15	4 × 250	5 × 250	1.25	12 × 250	14 × 250	1.17	40 × 250	46 × 250	1.15
Ovalle	1.15	4 × 250	5 × 250	1.25	12 × 250	14 × 250	1.17	40 × 250	46 × 250	1.15
Valparaíso	1.1	4 × 250	4 × 250	1	12 × 250	13 × 250	1.08	40 × 250	44 × 250	1.1
Santiago	1.1	4 × 250	4 × 250	1	12 × 250	13 × 250	1.08	40 × 250	44 × 250	1.1
Concepción	1.15	4 × 250	5 × 250	1.25	12 × 250	14 × 250	1.17	40 × 250	46 × 250	1.15
Puerto Montt	1.25	4 × 250	5 × 250	1.25	12 × 250	15 × 250	1.25	40 × 250	50 × 250	1.25

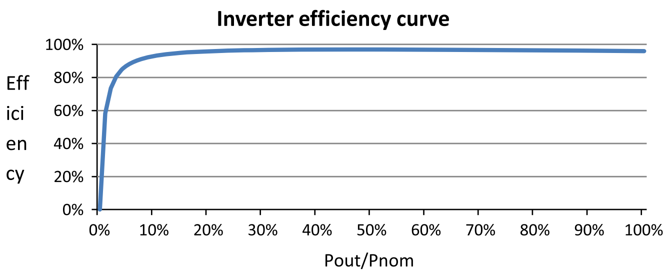

Fig. 7. Inverter efficiency curve.

Table 5
Average, maximum and minimum power losses reported in the literature and the value used for each.

Sources of loss	Minimum and maximum values reported (%)	Typical or average value reported (%)	Used value (%)
Nearby shadows	0.3–35	4	2
Incident angle modifier	2–3.1	2.6	2
Module 1	degradation	0.5–1	0.7
Temperature	2.2–17	4.7	2.2–4.9
Soiling	1.5–10	4.5	4.5
Mismatch	0.2–9.8	4	3
Wiring	0.24–2.5	1	1
MPP	0.6–15	1	1
Inverter	4–17.5	10.1	3.5–4

3.3. Power losses sources

Power losses in general are originated by nearby shadows, the incident angle modifier (IAM), module degradation, temperature, soiling, mismatch effect, wiring, MPP differences and finally the inverter losses (which was discussed above). Temperature losses are analyzed in more detail using the NOCT methodology [23,24]. Other losses are estimated using a compilation of losses made by Notton et al. [25]. All power loss sources are summarized in Table 5.

3.4. Results of PV generation and performance ratio

The results of the annual and monthly generation in kWh per kW installed for optimal, north and east orientations with their optimal inclinations are calculated. Then, considering optimal orientation and inclination, the evolution of the Performance Ratio is determined over time (up to 20 years of operation).

3.4.1. Annual and monthly generation for all locations

Energy production in optimal and north orientations is very similar, because the difference in the gain of GHI between those orientations is very small as shown in Figs. 8 and 9. However, production with an eastern orientation is much lower than with northern orientation, but allows more generation in the summer at the expense of the winter months.

The annual production is directly related to radiation levels, where Calama (in the north) shows the best production (2442 kWh/kW year) and Puerto Montt (in the south) has the lowest production (1360 kWh/kW year). Fig. 10 shows the optimal annual energy production for each location.

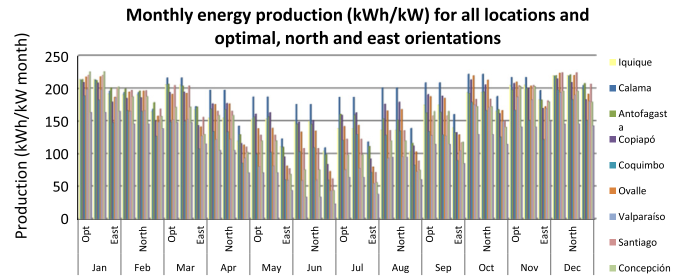

Fig. 8. Monthly energy production (kWh/kW) for all locations and optimal, north and east orientations.

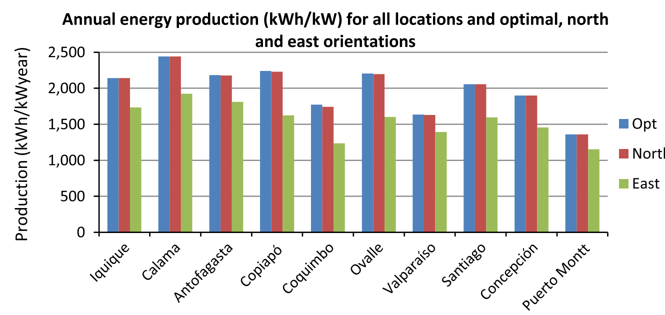

Fig. 9. Annual energy production (kWh/kW) for all locations and optimal, north and east orientations.

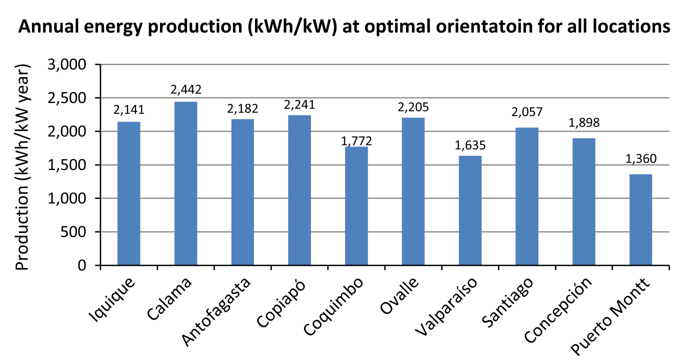

Fig. 10. Annual energy production (kWh/kW) for all locations and optimal orientation.

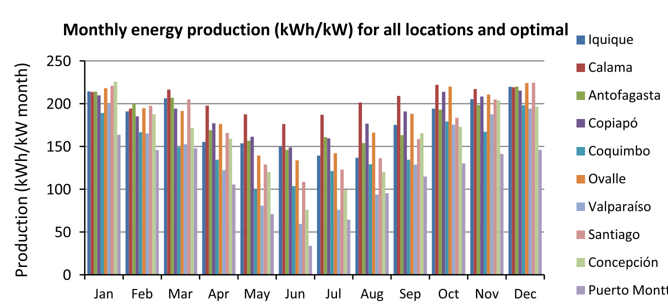

Fig. 11. Monthly energy production (kWh/kW) for all locations and optimal orientation.

Seasonality of monthly production in optimal orientation is shown in Fig. 11, which illustrates that the generation in winter in some cities, such as Calama, is similar to the generation in the summer. In other cities such as Puerto Montt, the difference in

production between the two seasons is significant, with as much as 3 times more production in the summer months.

3.4.2. Performance Ratio analysis

Performance Ratio (PR) is currently one of the most used indexes to determine the quality of a PV system. The Performance Ratio represents inverter proces efficiency by comparing the measured solar irradiance at the site with the measured power that leaves the inverter.

The difference between 1 and the value of PR represents the total percentage loss of the photovoltaic system [26,27], but also could include moments of failure or unavailability with regards to a system that would work optimally under standard conditions (STC) throughout the year [28]. However, in this work these failures will not be considered because unavailability is usually extremely low. The expression used to consider all the losses of the analysis is presented in Eq. (7)

$$PR = n_{sh} \cdot n_{IAM} \cdot n_{deg} \cdot n_{tem} \cdot n_{soil} \cdot n_{mis} \cdot n_{net} \cdot n_{mpp} \cdot n_{inv} \tag{7}$$

where each one of these terms corresponds to the power losses of nearby shadows (n_{sh}), incident angle modifier (n_{IAM}), module degradation (n_{deg}), temperature (n_{tem}), soiling (n_{soil}), mismatch (n_{mis}), wiring (n_{net}), maximum power point (n_{mpp}) and inverter losses (n_{inv}).

Using this definition, PR values have been determined for each city in the first year of operation and for years 5, 10, 15 and 20, because the degradation loss of PV modules is cumulative. The Performance Ratios are shown in Table 6, with resulting values of 84% in year 1 and 67% at year 20.

Studies conducted recently on thousands of operational photovoltaic installations in France [26] and Belgium [27] found performance ratios that range between 82% and 74%, while another study has reported performances ratios between 72% and 62% in several European countries [29]. The results for the performance ratio in this study are consistent with the results from the studies reviewed in the literature.

4. Net Metering and Net Billing computation

Net Metering is an electricity policy which allows utility customers who own a PV system to offset some or all of their electricity consumption with their local production. This works by utilizing a meter (or sometimes two meters) that is able to spin in two directions, showing either the net consumption or the net excess during a period of time. This excess generation or net consumption is then valued at the end of the period [6] usually at the retail rate. This policy promotes distributed generation because the retail rate paid to the PV system owner is higher than what would be received by a conventional generator for the same electricity. The retail rate that the PV system owner receives also includes the payment for the distribution infrastructure, implicitly becoming a subsidy for distributed PV development.

Net Billing is a variant from Net Metering, where the metered consumption is kept in a different record than the excess energy injected into the network. Excess energy and consumption are valued separately and at different prices. Energy consumption price is the whole retail price while excess energy is usually valued only at avoided cost (utility electricity generation cost plus avoided losses). Thus, the difference between these two prices is the payment for the distribution infrastructure, which under Net Billing goes to the distribution company instead of the PV generator. Fig. 12a and b summarizes this situation for Net Billing and Net Metering schemes respectively.

An example of the impact of Net Metering and Net Billing schemes on the value of PV energy for the 3 kW system is shown in Fig. 13a,b. In this case the 3 kW system has an annual production of 7325 kWh and there is a household consumption of 7865 kWh. In both schemes the amount of surplus (4748 kWh) and net consumption (5288 kWh) stay the same. However, the excess energy injected into the network is valued with different rates: 0.184 US$/kWh in the case of Net Metering and 0.108 US $/kWh in the case of Net Billing, as shown in Fig. 13.

While Net Metering has been commonly used in the developed world for decades, the Net Billing model is more recent and is of

Table 6
Performance ratios for all locations and 1, 5, 10, 15 and 20 operation year.

Year	Iquique (%)	Calama (%)	Antofagasta (%)	Copiapó (%)	Coquimbo (%)	Ovalle (%)	Valparaíso (%)	Santiago (%)	Concepción (%)	Puerto Montt (%)
1	82	83	82	82	82	82	83	81	83	77
5	79	80	78	79	79	79	80	78	80	74
10	75	76	75	75	75	75	76	74	76	70
15	71	72	71	71	71	72	72	71	72	67
20	68	69	68	68	68	68	68	67	69	64

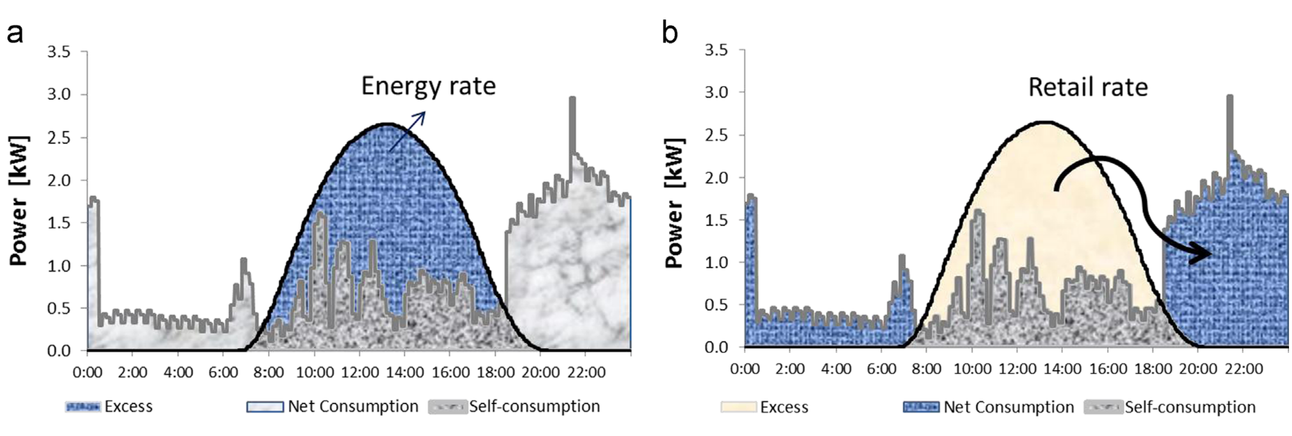

Fig. 12. Graphic scheme of offsetting household consumption in case of Net Billing (a) and Net Metering (b) scheme with a PV system.

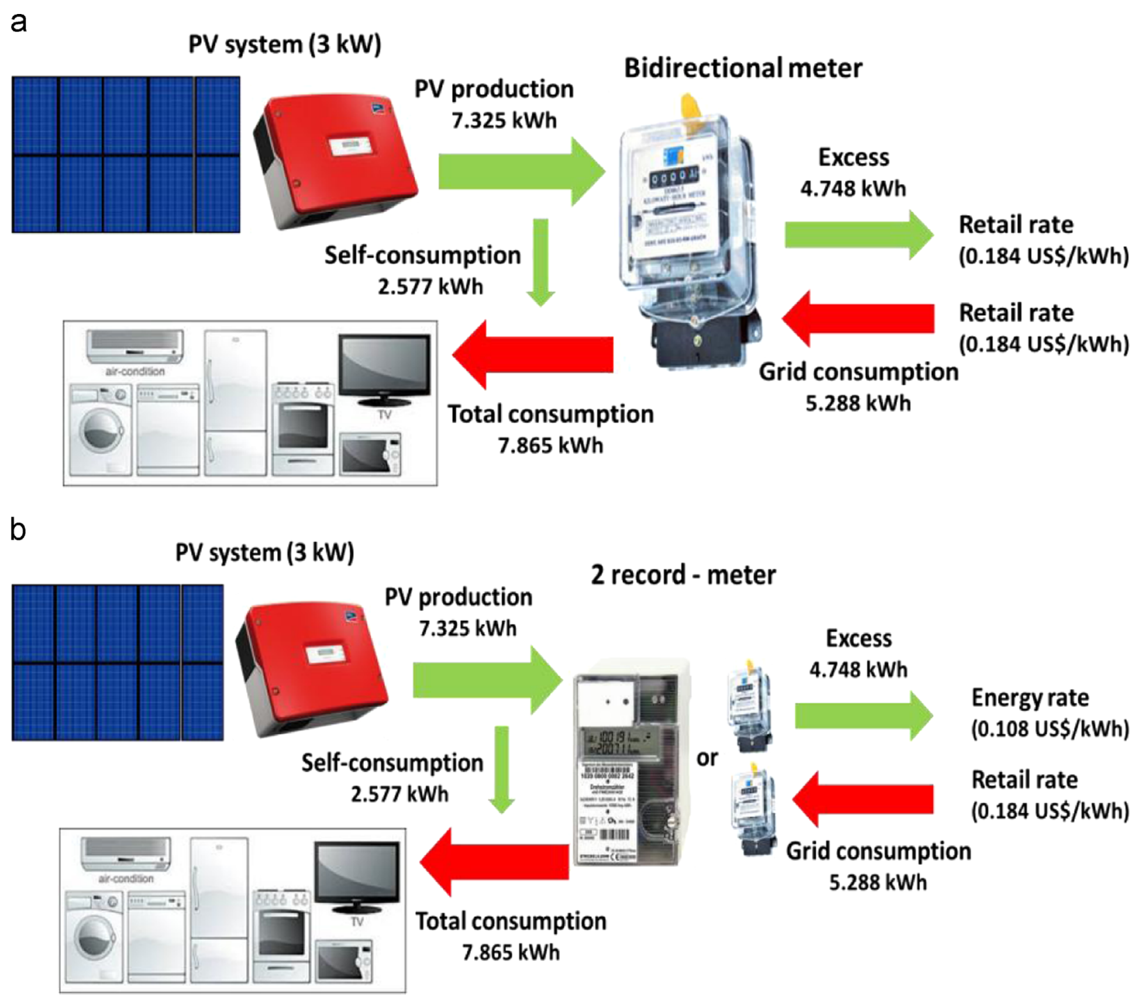

Fig. 13. Net Metering (a) and Net Billing (b) configurations. The excess of energy is valued at different rates (0.184 US$/kWh and 0.108 US$/kWh respectively) which is recorded by a 2 record meter under Net Billing.

interest to most developing countries. In Chile a Net Billing scheme was approved for small generators with capacities up to 100 kW, through the law No. 20.571 in February 20, 2013 [7]. However new changes to this law are in discussion, where a Net Metering scheme is suggested for consumers with capacities up to 10 kW [8].

In Net Billing, the definition of the integration intervals that the meters use is essential to establish the cost-effectiveness of PV generation systems, because it establishes how much of the energy is valued at a high and low rate.

Net Billing meters record high frequency readings, but can be programed to add those readings up over a specified period of time (called an *integration interval*) and to compute one final reading after every time interval. Inside each specific time interval, generation and consumption can cancel out even though they are not perfectly coincident in time, allowing a sort of "net metering" inside each *integration interval*.

This final reading of each integration interval is stored as either net consumption or net production. This proves to be important to the economic feasibility of PV installations under Net Billing because PV generation is variable and not always coincident with consumer loads. Ultimately, the *integration interval* definition establishes how much energy is valued at a high rate (consumer rate) and how much at a low rate (excess).

Most common modern electricity meters often make high frequency readings that integrate and record every 15 min. Thus, excess injections and net energy consumption inside the same time interval are added up to produce just one reading that is either positive (and stored as net consumption) or negative (and stored as excess generation). Under Net Billing, if the integration interval is increased to a whole day, it would allow PV generation during the day to offset night consumption, making PV generation more profitable.

In this work Net Metering and Net Billing schemes are compared, considering integration intervals of 1 (simulating instantaneous net balance), 5, 15, 30, 60 min, 1 day and 1 month. Integration intervals of 1 min limit the opportunities for PV generation and consumption to cancel out. This is also similar to the case where two separate meters are used to perform Net Billing, as they instantaneously separate consumption from excess generation. Integration intervals of 5, 15, 30, 60 min, 1 day and 1 month require installing one meter with a programmable integration interval capability.

4.1. Analysis and estimation of household consumption

For simplicity, a representative Chilean household was used to illustrate the affects of Net Metering or Net Billing across the study area. Since there no publicly available electricity profiles, an audit was conducted at the representative household that included observations and interviews (including metering at 1-min intervals for 3 weeks). Using the results of the audit, load patterns were identified over the year, including their hourly, daily, monthly and other seasonal variability for all electrical appliances. This produces 29 daily profiles

(with 10-minute resolution) which are used to represent each of the 365 days of the year, including weekdays, weekends, vacation days, holidays, hot weekend days, etc. These representative days were validated with measurements of consumption and were adjusted using monthly billing during one year.

The representative household consumed 7865 kWh/year, which is much more than average Chilean residential electricity consumption of 1800 kWh/year [30]. The household represents a typical economic ABC1 stratum consumption (highest consumption stratum). This stratum was necessary to make considering a 10 kW PV installation realistic and it is the stratum that most likely would invest in a PV system.

4.2. Model formulation

The variables used in this model are the local generation consumed, the excess energy, the net consumed energy and the income for selling the excess, the self-consumption and the PV energy value. For the energy balance a formulation proposed by Poullikkas and Yamamoto [6,31] is considered, but some modifications are introduced to account for the Net Billing scheme.

For a residential, grid connected system, the following variables were considered: the energy consumed (*Cbase*) and the total energy generated (*Gen*) by the residence, locally consumed generation (*Gcons*), excess energy (*Exc*) injected into the network (when local consumption is lower than generation), and net consumption (*Cnet*) from the residence (when local consumption is higher than generation).

Thus, the excess energy is the local generation less the local consumption when the generation is greater than consumption ($Cbase < Gen$) and the home sells energy to the network. In this case, there is no net consumption. The net consumption is the total consumption minus the generation when the consumption is greater than generation ($Cbase \geq Gen$) and the home buys energy from the utility. In this case, there is no excess energy. The following Eqs. (8) (through 13) express these relationships:

$$Gcons_{i,j,k} = Gen_{i,j,k} \text{ for } Cbase_{i,j,k} \geq Gen_{i,j,k} \quad (8)$$

$$Gcons_{i,j,k} = Cbase_{i,j,k} \text{ for } Cbase_{i,j,k} < Gen_{i,j,k} \quad (9)$$

$$Exc_{i,j,k} = Gen_{i,j,k} - Cbase_{i,j,k} \text{ for } Cbase_{i,j,k} \leq Gen_{i,j,k} \quad (10)$$

$$Exc_{i,j,k} = 0 \text{ for } Cbase_{i,j,k} > Gen_{i,j,k} \quad (11)$$

$$Cnet_{i,j,k} = Cbase_{i,j,k} - Gen_{i,j,k} \text{ for } Cbase_{i,j,k} \geq Gen_{i,j,k} \quad (12)$$

$$Cnet_{i,j,k} = 0 \text{ for } Gen_{i,j,k} \geq Cbase_{i,j,k} \quad (13)$$

where *Gcons*, *Cbase*, *Gen*, *Exc*, *Cnet* correspond to the local generation consumed, the consumption, the total energy generated, the excess energy and the net consumption for each day "*i*" = 1, 2… 365 and day-moment "*j*", which for example for a 30-minute interval is ranging from $j=1$ to $j=48$. The interval "*k*" can take values of 1 min, 5 min, 15 min, 30 min, 1 h, 1 day and 1 month.

Then incomes are calculated for each of the different time integration intervals, depending on the revenue rate used for offsetting consumption and excess energy, which in the case of Net Billing is different. Thus, for Net Metering, the total power generated was considered regardless of the fact that generation was actually consumed or generated. In addition, under Net Metering, the total income is the value of the local generation using the BT1 tariff (retail tariff) while under Net Billing the local generation consumed is valued at the BT1 tariff price but the excess generation is billed at the BT2 tariff price (energy-only tariff). This is shown in the equations bellow, which represent the total income during one year for Net Metering (Eq. (14)) and Net Billing (Eq. (15)) schemes, respectively.

$$IncNM_k = \sum_i^n \sum_j^{m_k} (Gcons_{i,j,k} + Exc_{i,j,k}) \cdot P_{BT1} = \sum_i^n \sum_j^{m_k} Gen_{i,j,k} \cdot P_{BT1} \quad \forall\ k \quad (14)$$

$$IncNB_k = \sum_i^n \sum_j^{m_k} (Gcons_{i,j,k} \cdot P_{BT1} + Exc_{i,j,k} \cdot P_{BT2}) \quad \forall\ k \quad (15)$$

where $IncNM_k$ and $IncNB_k$ correspond to the total income during one year for Net Metering and Net Billing schemes respectively, for each integration interval and BT1 and BT2 rates. In addition, *Gcons*, *Gen*, *Exc* correspond to the local generation consumed, the total energy generated, the excess energy and the net consumption for each day "*i*" = 1, 2… 365 and day-moment "*j*", which for example for a 30-minute interval is ranging from 1 to 48. The interval "*k*" can take values of 1 min, 5 min, 15 min, 30 min, 1 h, 1 day and 1 month. P is the price.

Finally, the PV energy price is obtained from the ratio between the total income and the total energy generated by the PV system, as described in the formulas (16) and (17) below.

$$PVvalueNM_k = \frac{IncNM_k}{Gen_{i,j,k}} = P_{BT1} \quad (16)$$

$$PVvalueNB_k = \frac{IncNB_k}{Gen_{i,j,k}} \quad (17)$$

where $PVvalueNM_k$ and $PVvalueNB_k$ represent the PV energy price under Net Metering and Net Billing, respectively and $IncNM_k$ and $IncNB_k$ correspond to the total income during one year for Net Metering and Net Billing schemes respectively, for each integration interval and BT1 and BT2 rates. *Gen* corresponds to the total energy generated, for each day "*i*" = 1, 2… 365 and day-moment "*j*", which for example for a 30-minute interval is ranging from $j=1$ to $j=48$. The interval "*k*" can take values of 1 min, 5 min, 15 min, 30 min, 1 h, 1 day and 1 month.

Thus the PV energy price is a measure of the commercial value of PV production according to the local utility rates and all other relevant factors described in this article, including consumer electricity profile, PV size relative the consumption, GHI, equipment efficiencies, etc.

4.3. Net Metering results

The amount of PV generation locally consumed and the excess energy generated and injected into the network depends on the size of the installation and integration time-interval used. For any given household and at any time-interval, as the system size increases, there is a greater possibility that the energy generated is greater than local consumption, which results in more excess energy injected into the grid [32]. This is particularly relevant in the case of Net Billing, where this excess energy is valued at lower rates. Thus, under Net Billing the value of the energy generated by the PV system decreases as the size of the PV system increases.

Fig. 14 is an example of the average power generated, consumed (net and self-consumed), and generated for a 1-min integration interval (nearly instantaneous integration), when considering photovoltaic system sizes of 1, 3 and 10 kW in Santiago.

This is also true annually, where excess energy is reduced when the integration time-interval increases, but these figures depend largely on the capacity of the PV system installed relative to the consumption profile, as shown in Fig. 15.

Under Net Metering (and considering cities with high GHI and electricity rates), increased generation through larger-size systems (oversized relative to consumption) could lead to higher profits to homeowners (the opposite is true with Net Billing). However, an

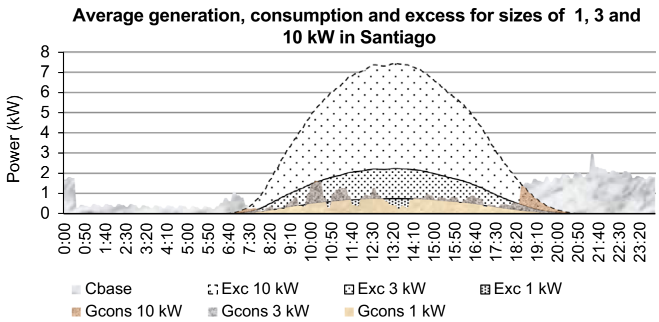

Fig. 14. Average generation, consumption and excess for sizes of 1, 3 and 10 kW in Santiago.

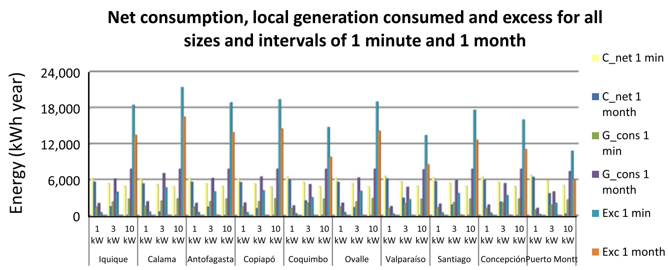

Fig. 15. Net consumption, local generation consumed and excess for all sizes and intervals of 1 min and 1 month.

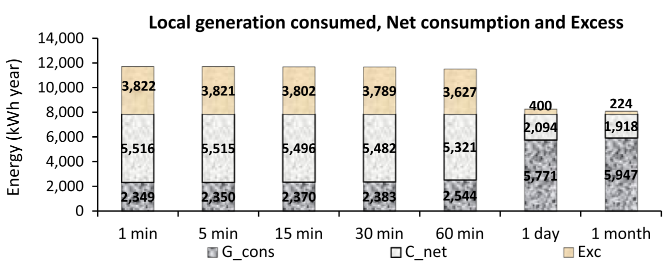

Fig. 16. Local generation consumed, net consumption and excess.

agreement with the utility must be made to establish how this excess energy will be reimbursed to the customer (e.g., monthly, quarterly, yearly) or if those excesses are permanently lost [6].

Under Net Billing, for installations with electricity generation similar to that which is consumed, the integration time-interval has great relevance, especially moving from minutes to one day and one month intervals. For a medium installation (3 kW) in Santiago, as the time-interval increases to one day, the self-consumed generation increases notably, while excess generation is reduced by the same amount. This occurs because when increasing the integration time-interval, there is a greater possibility that the energy that has been generated in a time-interval can offset the local consumption without requiring simultaneity between consumption and generation. Large integration time-intervals are beneficial for homeowners under Net Billing. In a Net Metering scenario this is often irrelevant because the energy is valued at the same price (usually the retail rate). Fig. 16 illustrates this.

Figs. 17–19 show local generation consumed, net consumption and excess energy, for the 1 kW and 3 kW system. It can be seen in the figures that the range of integration time-intervals for the case of the 1 kW system is not as relevant as it is for the 3 kW system. This is because with 1kW system energy production is often below the local consumption levels, thus most production is being

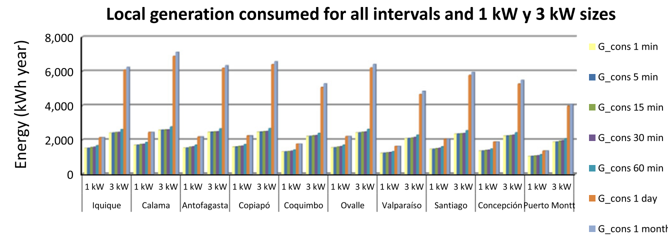

Fig. 17. Local generation consumed for all intervals and 1 kW and 3 kW sizes.

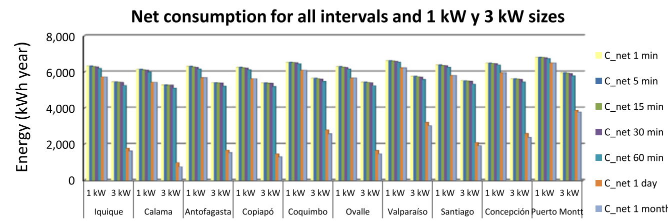

Fig. 18. Net consumption for all intervals and 1 kW and 3 kW sizes.

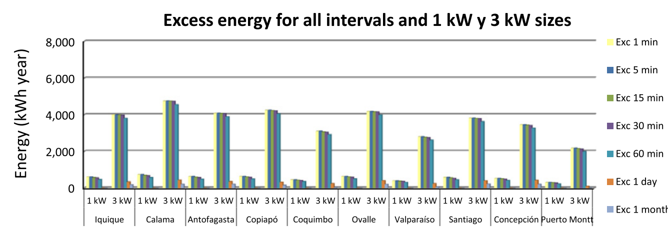

Fig. 19. Excess energy for all intervals and 1 kW and 3 kW sizes.

self-consumed no matter what time-interval is chosen (there is limited excess energy).

4.4. PV electricity price

Using production and total income from Net Metering and Net Billing schemes, the PV electricity price was obtained. This measures the commercial value of PV production considering all local conditions.

Under Net Metering the PV electricity price is equal to the retail rate (BT1) for each city. While under a Net Billing scheme this value depends on the self-consumption and excess generation ratio, where the excess generation is valued at the BT2 rate.

For PV electricity price calculation the utility rates (BT1 and BT2) for June 2013 are considered, for each city and utility including added value tax, as presented in Table 1. The BT2 rate is the energy rate for clients who pay capacity (peak power consumption) separately from energy. This rate is lower than the BT1 rate, which has both cost components together in one rate. BT2 is approximately the avoided cost of the utilities as it does not include distribution infrastructure costs, which are often nearly half of the BT1 rates.

Considering all sizes of installations and integration intervals, the value of the PV electricity price under Net Billing is greater for smaller installations and longer integration time-intervals, both of which reduce the amount of lower value excess energy. The BT1 energy rate represents the highest PV electricity price within each city and the BT2 rate as the lower limit according to the respective utilities. This means the value of PV electricity ranges from the full retail rate (when energy is accounted for as own consumption) to the avoided costs to the utility. Fig. 20 shows the PV energy value

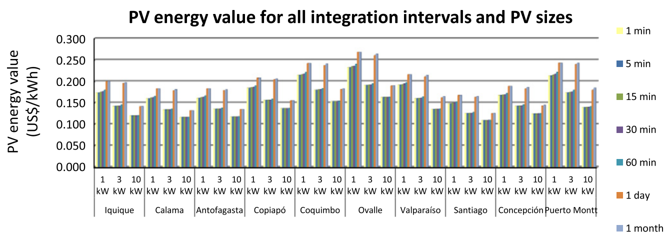

Fig. 20. PV energy value for all integration intervals and PV sizes for all locations.

for the first year as a function of the three PV sizes and all integration interval times used.

The PV energy production value presented considers the energy production of the first year, which is the largest, as production will decrease in the next years due to degradation of the PV modules.

5. Economic results

One of the most common and easy-to-understand ways of establishing the economic feasibility of a PV system is through a study of the levelized cost of electricity, LCOE [2,33–36]. This work represents the first LCOE study of PV in Chile. In this work LCOE are obtained for different investment scenarios (with and without debt) and discount rates, which are compared with retail rates from utilities, as well as the value of PV electricity after considering Net Metering and Net Billing schemes.

5.1. Formulation of levelized cost of electricity

Levelized cost of electricity is the ratio between the present value of total costs of the PV system, and the present value of the energy generated by the system during the evaluation period. The levelized cost of electricity is the minimum price of the energy at which the project can cover its costs. Eq. (18) shows the calculation for LCOE.

$$Levelized\ cost\left[\frac{\text{US\$}}{\text{kWh}}\right]=\frac{Total\ costs\left[\frac{\text{US\$}}{\text{kW}}\right]}{Energy_{Total}\left[\frac{\text{kWh}}{\text{kW}}\right]} \tag{18}$$

The present value of total costs, as shown in Eq. (19), considers the initial investment, debt (when applicable), and maintenance costs throughout the evaluation period.

$$Total\ costs\left[\frac{\text{US\$}}{\text{kW}}\right]=\left(Investment\left[\frac{\text{US\$}}{\text{kW}}\right]+Debt\left[\frac{\text{US\$}}{\text{kW}}\right]+Maintenance\left[\frac{\text{US\$}}{\text{kW}}\right]\right) \tag{19}$$

Investment, when modeled without debt corresponds to the total project value, while in the case with debt, it will be only 30% of the total project value, and the remaining 70% is debt service, which is paid over a 5-year period with a 15% rate as a consumer loan.

Capital costs are adjusted according to the inverter ratio (IR) to reflect that more capacity in PV modules is needed compared to inverter capacity (e.g. for 1 kW project, a 1 kW inverter is need plus a 1.25 kW of PV modules, incurring more cost where IR=1.25 as explained in Section 3).

In this study, projects are evaluated over 20 years, using three different discount rate scenarios, 6%, 10% and 14%, representing a range of potential investors from social to commercial evaluation rates. These scenarios where studied considering both debt (70% debt) and no debt. However, as PV market matures PV projects could be financed with a mortgage loan at a lower rate (5–6%). The following formulas were used to calculate debt component of cost and the annuity value required to feed that formula.

$$Debt=\frac{f}{r}\left(1-\frac{1}{(1+r)^{n_c}}\right) \tag{20}$$

$$f=\frac{V_c\times r_c}{\left(1-\frac{1}{(1+r_c)^{n_c}}\right)} \tag{21}$$

where f=annuity value, r=discount rate, V_c=Loan value ($V_c=0.7$ Project Value), r_c=discount rate of credit and n_c=time for loan repayment.

Annual maintenance costs are estimated as a percentage of the capital cost of the project and are considered to be 1%, as presented by Bazilian et al. [2]. This is presented in Eq. (22), where $Maintenance_{percentage\_cost}$ is 1%.

$$Maintenance_{Annual}=Maintenance_{percentage\_cost}\times Project_{value} \tag{22}$$

Therefore, the total maintenance costs can be calculated as the present value of the annual maintenance costs over the life of the project as presented in Eq. (23).

$$Maintenance=\frac{Annual_{Maintenance}}{r}\left(1-\frac{1}{(1+r)^{n}}\right) \tag{23}$$

where r=discount rate and n=period of study assessment.

The present value of electricity generated throughout the period considers a cumulative loss (p) of 1% per year due to the degradation of PV modules, which is expressed mathematically in Eq. (24).

$$Energy_{Total}=\frac{E}{r+p}\times\left(1-\left(\frac{1-p}{1+r}\right)^{n}\right) \tag{24}$$

where E=energy generated on initial year, r=discount rate study, p=annual loss factor and n=period of study assessment. This LCOE formulation (from Eqs. (17) to (23)) is based on [33].

5.2. PV system costs

In order to obtain an accurate picture of PV system costs in Chile, a survey was conducted with the companies participating in the PV industry organization, the Solar Photovoltaic Node, which receives some government funding to develop and promote PV in Chile. In addition, other companies were contacted and PV prices were discussed. The discussion below summarizes the information about PV costs (kit PV modules and inverters) obtained.

The companies interviewed usually installed PV systems between 0 and 4 kW, and only one company interviewed provided systems of up to 15 kW. The lowest reported photovoltaic kit cost is 1.5 US$/W while the lowest installation cost is 0.5 US$/W leading to a minimum of 2.0 US$/W for PV systems installed.

Using the information obtained through the interview process, the average cost of the photovoltaic system base (modules and inverter) was found to be 2.2 US$/W (70% of total cost), where approximately 1.6 US$/W corresponds to modules (50%) and 0.6 US$/W to the inverter (20%). Meanwhile the structures of assembly and installation have a cost of 1.0 US$/W (30% of total). Thus the average total cost is 3.2 US$/W (including taxes), much higher than the lowest cost supplier. This information is summarized in Tables 7 and 8.

However, as the market matures PV cost variability will be reduced, and overall PV cost will fall as PV providers increase their installation volume and the low-cost providers dominate. This is expected to press the installed PV system cost down towards 2.00 US$/W and is in line with the expectation that the international price of components (especially modules) will continue to fall. For this study, PV installed cost are varied between 2.00 US $/W and 3.00 US$/W. This also corresponds with investment costs presented by Bazilian et al. [2], who presented the actual cost in

Table 7
Capacities and lowest and average cost reported for each company. Companies with little information are in red.

Company	Capacity range (kW)	Lowest cost ($/W)	Lowest cost (US$/W)	Average cost ($/W)	Average cost (US $/W)
Heliplast	2–15	899	1.81	965	1.95
Aquitosolar	0.3–3	1003	2.02	1295	2.61
Punto Solar	1.6–4.5	874	1.76	972	1.96
Tiendasolar	1.5–4	1132	2.28	1132	2.28
(Private)	0–10	744	1.5	992	2
Solinet	0.3–0.5	997	2.01	997	2.01
SolEnergy	0.3–0.5	1308	2.64	1408	2.84

Table 8
Structures of assembly and installation costs reported.

Company	Installation cost ($/W)	Installation cost (US$/W)
Heliplast	655	1.32
Aquitosolar	551	1.11
Punto Solar	425	0.86
Tiendasolar	317	0.64
(Private)	248	0.5

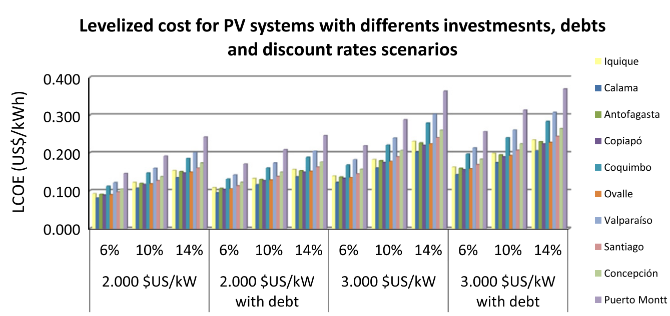

Fig. 21. Levelized cost for PV systems with different investments, debts and discount rates scenarios for all locations.

the world as around 3.00 US$/W for small systems, but projected that by 2015 costs would fall to 2.00 US$/W.

5.3. Levelized cost of electricity results

LCOE increases with higher investment cost and with debt, as the debt rate utilized here is relatively high. The case with 2.00 US $/W without debt and using a 6% discount rate represents the lowest LCOE, reaching values near 0.1 US$/kWh, where Puerto Montt in the south is an exception. The highest LCOE is found with investment of 3.0 US$/W with debt and a 14% discount rate. In this scenario, the LCOE reaches in average values of 0.2 and 0.3 US $/kWh. Puerto Montt again is an exception with a LCOE close to 0.4 US$/kWh.

The cities with lower LCOE (under 0.1 US$/kWh) also have higher radiation levels. This is the case for Iquique, Calama, Antofagasta, Ovalle, Santiago and also Concepción, with a capital investment of 2.0 US$/W and discount rate of 6%. Levelized costs of electricity (LCOE) are presented Fig. 21.

The levelized costs are compared with the PV energy prices obtained in the Net Metering and Net Billing schemes analysis. PV energy price represents the value of the production of the PV project, while LCOE values represent the costs of installing and running such system. Thus, when PV energy prices are higher than their LCOE, a PV project is cost effective.

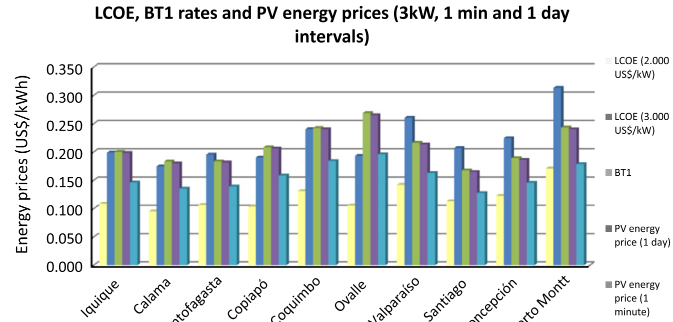

Fig. 22. Levelized cost with an investment of 2.0 US$/W and 3.0 US$/W, installation of 3 kW PV energy prices considering integration intervals of 1 min and 1 day (Net Billing), and BT1 rates (Net Metering).

The comparison considered the 3 kW PV system production, a 10% discount rate without debt, two different investment scenarios (2.0 US$/W and 3.0 US$/W) and integration time-intervals of one minute and one day, as shown in Fig. 22. Those two time-intervals are chosen because they are the most commonly addressed values in local policy discussion and they are different enough to produce significant changes in LCOE.

In the case of Net Metering, PV energy prices are the same as retail rate (BT1), which are higher than the PV LCOE in the northern cities (Iquique, Calama, Copiapó, Coquimbo and Ovalle) for both investment scenarios (low and high investment costs). The most cost effective areas are in Coquimbo and Ovalle (where Ovalle is number one) because of the large difference between the rate (BT1) and the PV LCOE (cost). Therefore, these cities should be the focus of the PV industry development.

In case of Net Billing, with a low investment cost (2.0 US$/W), PV LCOE is less than the PV energy price calculated in all cities, regardless of the integration intervals (one day or one minute). Thus, PV projects are cost effective in all cities.

However, with an investment cost of 3.0 US$/W and an integration time-interval of one day, PV LCOE are less than PV energy price only for in Iquique, Calama, Copiapó, Coquimbo and Ovalle. Thus, under more expensive PV installation costs, PV projects are cost effective only in northern cities.

Finally, the use of an integration interval of one minute reduces the PV energy price considerably, while the high investment (3.0 US$/W) costs increases LCOE. Thus, under this less favorable scenario for both costs and PV energy price, PV energy price is lower than PV LCOE for all cities with the exception of Ovalle. This is the one city with such high electricity rates that PV systems are always profitable according to scenarios modeled in this study. Fig. 22 summarizes the levelized cost with an investment of 2.0 US $/W and 3.0 US$/W and a 3 kW array.

5.4. Payback time and IRR analysis

Table 9 below shows payback periods by city and considering both BT1 and BT2 utility rates. Payback periods are shown for investments of 2000 US$/kW (top line) and 3000 US$/kW (bottom line). BT1 and BT2 can be used as the upper and lower bounds by assuming all electricity produced by the PV system is either sold at the BT1 rate (highest bound – self consumption) or the BT2 rate (lowest bound – all exported). When a specific size PV system is used (1 kW, 3 kW and 10 kW) as well as a specific time integration interval (one minute and one day), the payback period falls between the upper and lower bounds of BT1 and BT2 because some of the electricity will be valued at the high rate and some at the low rate. The same approach was used for IRRs in Table 10.

Table 9
Payback periods for each city and investment levels of 2.000 US$/kW and 3.000 US $/kW, BT1 and BT2 rates and PV energy price for three sizes and integration intervals of one minute (1 min) and one day (1 d).

Payback 2000–3000 US$/kW								
	Utility rates		1 kW		3 kW		10 kW	
City	BT1	BT2	1 min	1 d	1 min	1 d	1 min	1 d
Iquique	6	11	7	6	8	6	10	8
	9	18	10	9	13	9	16	13
Calama	5	9	6	5	8	6	9	8
	8	15	9	8	12	9	14	12
Antofagasta	6	11	7	6	9	6	10	9
	10	18	11	10	13	10	16	14
Copiapó	5	9	6	5	7	6	8	7
	8	14	9	8	11	8	13	11
Coquimbo	6	11	7	6	8	6	9	8
	9	17	10	9	12	9	15	12
Ovalle	4	8	5	4	6	4	7	6
	6	12	7	6	9	7	11	9
Valparaíso	7	13	8	7	10	7	12	10
	11	–	12	11	16	11	19	15
Santiago	7	12	8	7	10	8	12	10
	11	20	13	11	16	12	19	16
Concepción	7	12	8	7	9	7	11	9
	11	20	12	11	15	11	18	15
Puerto Montt	8	19	9	8	11	8	14	11
	13	–	15	13	18	12	–	17
Max	8	19	9	8	11	8	14	11
	13	20	15	13	18	12	19	17
Min	4	8	5	4	6	4	7	6
	6	12	7	6	9	7	11	9
Average	6.1	11.5	7.1	6.1	8.6	6.4	10.2	8.6
	9.6	16.8	10.8	9.6	13.5	9.8	15.7	13.4

Table 10
IRR for each city and investment levels of 2.000 US$/kW and 3.000 US$/kW, BT1 and BT2 rates and PV energy price for three sizes and integration intervals of one minute (1 min) and one day (1 d).

IRR 2000–3000 US$/kW								
	Utility rates		1 kW		3 kW		10 kW	
City	BT1	BT2	1 min	1 d	1 min	1 d	1 min	1 d
Iquique	17%	6%	14%	17%	11%	17%	8%	11%
	10%	1%	7%	10%	5%	9%	2%	5%
Calama	19%	9%	16%	19%	12%	18%	10%	12%
	11%	3%	9%	11%	6%	10%	4%	5%
Antofagasta	16%	7%	13%	16%	10%	15%	8%	10%
	9%	1%	7%	9%	4%	8%	2%	4%
Copiapó	20%	10%	17%	20%	13%	19%	11%	13%
	12%	4%	10%	12%	7%	11%	5%	6%
Coquimbo	17%	7%	15%	17%	12%	17%	9%	12%
	10%	2%	8%	10%	5%	9%	3%	5%
Ovalle	25%	12%	22%	25%	17%	25%	14%	17%
	16%	5%	13%	16%	9%	15%	7%	9%
Valparaíso	14%	4%	12%	14%	8%	13%	6%	9%
	7%	−1%	5%	7%	3%	6%	1%	3%
Santiago	13%	5%	11%	13%	8%	12%	6%	8%
	7%	0%	5%	7%	2%	6%	1%	2%
Concepción	14%	5%	12%	14%	9%	13%	7%	9%
	7%	0%	5%	7%	3%	6%	1%	3%
Puerto Montt	11%	1%	9%	11%	7%	12%	4%	7%
	5%	−4%	3%	5%	1%	6%	−1%	2%
Max	25%	12%	22%	25%	17%	25%	14%	17%
	16%	5%	13%	16%	9%	15%	7%	9%
Min	11%	1%	9%	11%	7%	12%	4%	7%
	5%	−4%	3%	5%	1%	6%	−1%	2%
Average	17%	7%	14%	17%	11%	16%	8%	11%
	9%	1%	7%	9%	5%	9%	2%	5%

Naturally payback time is lower and projects have the highest return when the investment cost is low (2.0 US$/W) and the price of PV energy sold to the network is equal to the full retail rate BT1. Ovalle has the best results with a payback of 4 years and 25% IRR for 1 kW and 3 kW projects. This is due to their high energy prices, despite not having as much radiation as Calama. Calama, the city with highest GHI in Chile, has a 6 year payback and 19% IRR for 1 kW projects. 3 kW projects here have 8 year payback and 18% IRR.

When the investment is 3.0 US$/W, still under BT1, the payback period increases by an additional 3–4 years in the cities of northern Chile and by an additional 5–6 years to the South. Meanwhile, the IRR of the different cities is between 5% and 12% under a BT1 rate, except in Ovalle where the IRR is 16%.

When the PV system size is increased (to 10 kW) with 1 min time interval, returns remain at profitable levels with an investment of 2.0 US$/W. But when the investment is increased up to 3.0 US$/W project economic performance decreases considerably. In addition, the payback periods become very long in nearly all cases.

6. Conclusions

In this study a comprehensive analysis of small-scale PV production and economic feasibility was conducted, demonstrating a huge potential for residential PV growth and development in Chile. The results of this study underscore the opportunity to take advantage of the country's high irradiation levels to help combat high, volatile electricity prices and alleviate a dependence on imported fossil fuels. Furthermore, this study thoroughly compared Net Metering and Net Billing policy schemes, highlighting the potential for policy makers to accelerate residential PV development in Chile through thoughtful regulation.

A thorough residential PV production model was developed for 10 cities throughout Chile in order to develop an accurate picture of potential residential PV technical performance. A detailed minute-by-minute production simulation was conducted, considering local radiation data, optimal orientation and inclination, systems size with optimal inverter ratios, and the main power losses of the systems.

The value of residential PV system production under Net Metering and Net Billing schemes was compared. Under a Net Metering scenario all excess PV production that is exported onto to the electricity grid is valued at the full retail rate. This generally means that exported PV electricity is of equal value to self-consumed electricity. However, Chile, and most developing nations are far more likely to implement some version of net billing, in which exported electricity is bought a rate that is lower than the retail rate. This study considered the impact of increasing time integration intervals (ranging from minute to one month) on the value of PV electricity production under Net Billing. Under Net Billing, longer time integration intervals can positively impact the cost effectiveness of a PV system.

In each city, the PV production energy prices were calculated considering various production scenarios (variation in PV array size and time integration intervals, the later of which effects the price at which PV electricity is sold to the grid). These energy prices were compared to a LCOE for the system, which was based on investment and maintenance costs. In all cases, shorter integration periods under Net Billing schemes, and over-sized PV arrays negatively effect the PV system economics. In some cases, these factors make the projects very unattractive for investment. Conversely, long-integration periods and appropriately sized systems (smaller than local consumption) lead to cost effective PV projects in every city.

In Net Billing an integration interval of one day allows PV generation to compensate for the increased consumption at night. In this case all the energy produced by a PV system could be valued at the full retail rate. Whereas, an integration interval of one minute, does not allow for compensation of consumption at different moments of the day, especially in hours when the PV system is not producing energy. Furthermore, one minute intervals cannot compensate for high consumptions in short timeslots.

The average value of PV energy exceeds 0.25 US$/kWh for residential installations in Ovalle with sizes of 1 and 3 kW. While in cities with higher radiation than Ovalle but with lower energy prices like Calama, PV energy value is around 0.20 US$/kWh. Despite Santiago's high radiation levels compared to nearby cities, low electricity rates make PV systems less cost-effective. Coquimbo shows the reverse situation, where their radiation is low compared to nearby cities, but the electricity rates are very high making PV generation more valuable.

Because all systems sized are compared to the same consumption profile, the size of a PV system is directly related to the amount of excess energy exported. Therefore, under a Net Billing scheme, larger PV arrays decreases the average PV energy price, because a greater proportion of energy is valued at a lower rate instead of the full retail rate.

With respect to the cost of PV systems, 2000 US$/kW investments are expected in the next years in Chile, when the PV market are more mature and competitive. Under this cost scenario, PV installations could be profitable in all cities studied (depending on the discount rate and evaluation time chosen) even under Net Billing scheme. With higher installation costs economic feasibility becomes sensitive to local conditions throughout Chile.

Residential PV systems under a retail rate are paid back in 6 years on average, while in the best case, Ovalle, pays back in just 4 years. IRRs range from 16% to 25% in this city, depending on investment cost assumption. These numbers demonstrate the strong potential for residential PV systems in Chile.

The findings of this study underscore the potential of residential PV in Chile to help alleviate the nation's energy crisis and to contribute to cleaner electricity generation. Policy makers can influence time integration periods used in Net Billing schemes to accelerate the residential PV market and incentivize investment in distributed residential PV. World wide, countries have an opportunity to accelerate PV development by drafting Net Metering schemes that allow for PV generation to compensate for energy usage over a larger period of time.

Acknowledgments

The authors thanks CONICYT funding by FONDECYT project 1141082.

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